ALASKA STATE LEGISLATURE

SPECIAL SESSION

THE ALASKA GAS PIPELINE

MAY 17, 2006

9:00 a.m.

Taken at:
Centennial Hall
Juneau, Alaska

Reported by: Sandra M. Mierop, CRR, CCP

PROCEEDINGS

COMMISSIONER CORBUS: Good morning, everybody. Could we please take our seats so we can get started?

Thank you.

Good morning. Can we please call the presentations, meetings back to order?

I'm told that it's not covered under the confidentiality agreement, but I have --

SENATOR HUGGINS: Mr. Corbus, question for you before we get started, actually for everyone. Would everyone, could you please stand. We have a birthday with us today, Senator Bettye Davis.

[Applause]

[Legislature sings "Happy Birthday" to Senator Bettye Davis.]

[Applause]

COMMISSIONER CORBUS: Thank you, and happy birthday.

Again, the -- we will accept written questions at the end of each presentation, so I encourage you to get your questions up as -- as the presentations are being made.

This morning, we have the -- the topic is: Challenges of State Ownership and, in particular, Capacity Management and Marketing Management.

Ken Griffin, the Deputy Commissioner of the Department of Natural Resources, will make the two presentations.

Ken.

COMMISSIONER GRIFFIN: Okay. Well, thank you, Bill.

Good morning. I appreciate everyone's stick-to-it-iveness here. I know this has been a long process, and I've heard a couple of opinions. It's been a little bit tedious. And let me tell you, for those of us that have been doing this six or seven days a week for a little over two years, I agree with you wholeheartedly. But it's been exciting, also.

The topic is Challenges of State Ownership, talking about capacity management and then talking about marketing management. And we're really referring to these as challenges to try to distinguish them from the idea of risk. And I know that you all have heard a lot about the risks of this project. And you're going to hear more about it, the cost overrun risk and things like that.

And, certainly, there are risks in taking capacity commitments. There are risks in taking marketing commitments. But, unless the world is turned on its ear, these are manageable challenges that many businesses, large and small, manage every day, and they're challenges which the State -- State is fully capable of organizing entities that can meet these challenges on a daily basis on our behalf.

Before I get into that, I'd like to respond to -- a little more -- a little more to a question that Commissioner Menge responded to last night concerning the -- the PTU documents referenced in Article 23.2, and they're the expansion -- the July 31st, 2001 expansion agreement and the May 24th, 2002 findings of the Director.

Both of those are public documents. They are in the public file at DNR. They always have been. And they have been, as Mike said -- there have been one or two document requests from the Legislature that we responded to, so I know they're available around the Legislature. If you can't find them, we can get you some more. And, as Mike said, we are going to try to get these on the website related to the contract. But they are and they have been public documents.

So, let's get into it here.

First of all, I want to talk about capacity management, and I want to talk about -- a little bit about the basics, just to get us oriented together.

When we talk about capacity in this context, we're talking about the right to ship gas on a pipeline. And it comes in two generic forms. The first is what we call firm transportation. The right to ship is reserved by the shipper for a period of time -- a volume for a period of time. There's a reservation charge that gets paid, usually on a monthly basis, but up front.

The second form is interruptible transportation. This is the -- a situation where the shipper only buys capacity as it's used, or they make short-term commitments that meet their expectations for near-term delivery.

IT, interruptible transportation,

is not guaranteed.

Firm transportation, I'd like to go back to that a little bit, is common to back-stop financing of new construction. It's going to be necessary on our line.

IT is often used later in the life of pipelines, after the financing has been paid off. It may be more of a term-type commit- -- commitment, like I referred to earlier where the existing ship -- shippers have an ongoing first right to roll over their short-term fixed commitments, and then as time goes on, they're able to release a little bit and balance it with their expectations of their immediate deliveries.

But with that, let's go back and let's talk more about firm transportation. As I said, this is long-term. It's necessary for financing. Generally, or a lot of times it's tied to the financing period, you know, 10 -- or 15, 20, 25 years.

The risk is on the shipper who takes out that FT. The shipper assumes the risk of not being able to make deliveries for the FT they are paying for. And they also take the risk that the sales price does not cover shipping costs. And this might be a concern at very low gas prices, particularly if the construction cost was overrun and you had these additional dollars thrown in, jacking up the tariff.

Because of that, the creditworthiness of the shipper is a major concern for the pipeline and for the finance -- financiers. The open season will include creditworthiness standards for potential shippers. They will have to meet those creditworthiness standards before they will be awarded capacity.

I think I hit it twice.

Yeah.

I want to back up to that, because that's an important slide, and I don't just want to talk at it. The -- this slide and the next one are -- are the justification for the capacity article. And the fact is the State is not just like the producers. The State does not control development. We don't make production decisions. We don't control where exploration goes, whether it's going to occur on State lands, where 20 percent or so of the gas is ours, or whether it goes into federal and private lands, where some 7 percent is -- is State gas, or if it moves out into OCS waters where none of the gas is a State's share. So the State is at a differential risk of whether they're going to have gas available flowing later in the life of the contract, depending on the decisions the producers make.

And we don't have the same information they have. We are not a working interest owner in the units. And these differences create dependencies for the State, which are inconsistent with the type of commitments we have to make for capacity and for marketing.

And the fact that we have agreed to take our gas in kind is what creates this inequity, this dependency. And so the purpose of Article 10 is to balance these dependencies with the commitments -- with commitments from the producers.

And, more specifically, there are four purposes of Article 10. The first is to ensure that the State can get our gas to market as it's produced. The second is to ensure that the State does not bear disproportionate risk of unused capacity. The third is to ensure the

State has the information necessary to manage capacity and, more importantly, and I think, to market our gas on par with the producers. And then, lastly, of course, is to ensure the State retains the ability to meet in-state gas needs.

Now, the -- these issues aren't created by any ill-intent or any bad faith or anything like that on the part of the producers. It's -- it's simply the fact that we are in a different position than they are upstream, and Article 10 is needed to compensate for -- for those differences.

I'll give you a brief outline. Article 10 talks about how capacity is acquired. Then we talk about how a situation where the State has inadequate capacity to ship our gas, how that's rectified. We talk about ways of dealing with excess State capacity. Or if it can't be dealt with, how is responsibility for that excess capacity distributed equitably. We talk about short-term imbalances. These are the day-to-day matching of -- of throughput and deliveries. That's -- that's a day-to-day business management issue that's kind of outside the focus of the capacity management article, but it's still important, and the State needs to be on equal footing there.

And we talk about the capacity notice process, which is how these issues are communicated between the producers and the State. We have a section on information, and, again, this is the information necessary to manage capacity, but more importantly, to market our gas effectively.

There are grounds for termination of Article 10. We'll talk about that.

And then you have issues of -- of limiting damages, indemnifying the producer, commitments to comply with FERC and that sort of thing.

Under capacity acquisition, the State always has the right to go it alone in -- in acquiring capacity. And if down the road we decide that we're going to be better off managing our own business independently, we -- we have the right to acquire capacity independently, and we also have the right unilaterally to terminate this Article at any point and simply go it alone and manage our own business.

Otherwise, the State receives a

proportionate share of firm transportation obtained in the open season. And this is managed by property and by producer. So, if you have three -- three fields delivering gas and each field has three producers, we're going to be managing nine pieces of capacity between all those producers and the State.

Capacity will be obtained with the same duration, terms, and conditions, and it will be obtained in each element of the pipeline system. So you'll have pipelines delivering gas to the GTP. Each of those will need to be managed. Capacity will need to be managed through the GTP. I would assume capacity needs to be managed down to the first delivery point in Alaska, to the next one, to the next one, and then through the pipeline in Canada. So it's -- it's quite an accounting process.

If the State obtains capacity outside this article, what we have done is we've gotten out of balance with the producer, and so the producer capacity commitments terminate. We either ride their coattails on this, or we don't.

And, lastly, the State can make in-state commitments during the open season, and then those are sort of factored out of the balancing equation.

Let's talk about insufficient State capacity. The requirement in the contract is: If the producer plans to deliver gas in excess of existing State capacity, it shall satisfy any need for capacity required by the State. And there is a process listed in there. There are -- there are four alternatives: A situation where maybe the producer has excess capacity somewhere else on the North Slope and they simply redesignate that capacity to this property and release some of it to the State; or they acquire capacity, maybe from another producer, maybe the pipeline has added capacity for some reason, and they acquire that capacity and release the proportionate share to the State or maybe there's other options that under the circumstance will be agreeable.

Only if those actions do not eliminate the State shortage, there is a provision in the contract to allow the producer to purchase additional gas -- the -- the incremental gas from the State at AECO, minus the tariff. And that does create some -- a disproportionate situation there. There might be some issues that the State might lose a little bit of value there, but this is an only-if situation. And you've got to realize, if we're in a situation where there's insufficient State capacity, the producers' capacity is probably limited also. So, if they're going to purchase our gas, what are they going to do with it? Are they going to choke back some of their gas? In which case this problem starts to go away. Or are they going to put our gas back in the ground? None of these decisions are independent.

So there is an issue here, and I'll talk about it from a risk standpoint later on. But it's -- it's not what it might appear to be at -- at first blush.

And then the last thing, and the thing that I think most often will happen is that deliveries will simply be reduced to meet pipeline capacity.

And, again, the commitment in this article is that the producer capacity-holder shall satisfy any State capacity shortage.

Let's talk about excess capacity situation. If there's excess State capacity --

and this is -- the -- the technical term for this is owage, and I have to use that because Representative Hawker -- Hawker has just been fascinated by that word since he first heard it. So -- but the technical term here is owage. It's capacity that is excess and beyond the volume flowing through the line.

And there are two obviously desirable solutions here. One is either we can purchase gas to fill that capacity, or we can release that capacity to another producer and then eliminate those costs.

Either transaction, according to the Article, must be initiated by the producer, and then the State must participate in that -- in that business arrangement. The State receives the same terms and conditions the producer does, and so, you see, we stay locked arm in arm as we manage this.

The other situation with excess capacity is that nothing can be done to resolve it. The pipeline cannot be kept filled. And Article 10.4 provides for put rights, which is the right to transfer an obligation to the other party. And so the producer and the State have mutual rights to put unused capacity above their existing share of production to one another. So, if we're flowing somewhere near 20 percent of the gas, but the pipeline is not full, we will be bearing the costs of about 20 percent of that excess capacity. If production 25 years from now has shifted and it's out in federal acreage and our share of the gas is closer to 10 percent, then the State is going -- going to also be responsible for closer to 10 percent of that excess capacity.

There is a threshold volume to this put requirement. You would think that might create some risk for the State. Actually, it goes the other way, according to some of our risk analyses.

The whole purpose of this section is to protect the State if production shifts to nonState acreage. And -- and it's a matter of balancing our risk with the return we expect from our share of the gas.

There's some related issues that are dealt with briefly in the contract. The first is that the State has proportional excess to interruptible transportation. The term that's used in the contract is seasonal variability capacity. But if you look at the definition, it really is any form that is created of -- of interruptible transportation. It's in Article 8.8. It's not in Article 10.

The other thing that's addressed is this minor imbalances that I referred to briefly earlier -- earlier. This is daily variability in gas flow. It's addressed specifically in 10.5, and the -- the terms that are in here are: The producers must offer the State the same or substantially similar gas balancing terms. And there are other commercial tools available to manage your gas flow on a daily basis, whether it's transferring capacity, buying gas, things like that. All those sorts of commercial tools that shippers use are available to the State to manage our daily deliveries.

And these gas balancing terms, there will probably be something done through the LL -- LLC. There will be agreements with the -- the producer -- producing -- Prudhoe Bay, with the fields. And what this contract assures is that we have equal access to the terms of all those agreements however they develop. We have the same access to those terms that the producers have.

Information is discussed, and to me, this is -- is a major issue. And as I've said a couple times, the big issue I have here is that we need to be able to do projections and market our gas effectively on the long-term as well as in the short-term. And we need the same access to that critical information that the producer marketing companies have. And the term is that the information related to expected deliveries and production forecast information shall be promptly provided to the State capacity holder, and it shall be provided to the extent received by either an operator or the producer -- capacity holder's own producer.

And it's written in broad terms because we -- we want to insure that all that information, that we have -- we have access to it and that we can depend on it to -- to make our marketing decisions as we go forward.

We do have some termination clauses in here. Article 10 terminates if it's determined to be contrary to law. There is a commitment on the part of the producers that if that occurs, there will be good-faith negotiations to come up with an alternative.

We, at all times, have the uni- -- unilateral right to terminate this -- this article.

And, lastly, we have to stay in step with them. If we acquire or transfer capacity, if we purchase or sell gas -- this is on the North Slope -- outside of this contract, this contract would terminate, because we, by our actions, have gotten ourselves out of step with -- with the producers.

The damages, indemnity, and FERC sections basically specify that the producers are not paid or they're not compensated for facilitating State capacity acquisition or the balancing or anything else through this article. Except for fraud, they're not liable to the State for losses. So, if they acquire too much capacity and we, of course, got it also, they're -- they're not responsible for it. They've made their best business decisions, and we're riding their coattails, good or bad.

If breach occurs, the State may initiate a dispute. Specific performance is the award. The State shall indemnify each producer against loss. And lastly is the commitment, again, to comply with FERC.

We did have -- we've had -- we've looked at the risks associated with capacity several times. We have a recent risk analysis that was done by Lukens, and it was actually done on a prior draft of this contract, and so there were risks that they identified in their risks analysis that were later rectified by subsequent changes to the language.

So, what I did is I took their risk analysis and I tried to compare it to the language we have now, and this is a -- just a real brief assessment of what they found, given the language we have today. There's a little more extended discussion of this in the fiscal interest finding.

But the -- the Article 10.2, producer purchase of State gas at AECO minus the tariff, according to their estimates, exposes the State to some disproportionate risk of -- of not getting our value. They -- they quantify that risk at .05 to .42 percent of the total NPV benefits of the -- to the State.

And what this is is discounted net present value. It's -- it's not total revenues. It's net present value after all the costs and all have -- have come out. Our exposure due to that -- that purchase occurring is less than 1 percent of our expected net present value.

Another area they looked at was the -- the magnitude of risks due to excess capacity. And they estimated those to be somewhere from 3 to 11 percent of the net present value to the State. So, actually, that -- a little more significant.

But what they found is that that excess capacity risk is shared fairly proportionately between the producers and the State. The disproportionate risk between the State and the producers, again, is .14 to 1 percent of the total NPV to the State.

They found that the put threshold actually benefits the State to a very minor degree. I'm not sure I can explain -- explain why that is, but that -- that it was their assessment.

And the last thing I want to talk about is that these -- these numbers are magnitudes of risk. They're saying: If these scenarios were to occur, these are the range of magnitudes of the risk you might see. They don't -- they didn't talk about the chance that we might have excess capacity risk, the chance that the producer would be -- or the frequency with which the producer might be buying State gas. So, when you start looking at these magnitudes, these numbers, and then comparing them to the frequency or the likelihood of occurring, you see that these numbers become, I think, very manageable for the State.

In summary, I think that this Article has done a good job of -- of balancing the risk incurred by the State due to taking State gas in kind with those accepted by the producers.

The -- the absolute magnitude of those risks, as I said, is manageable.

And the likelihood of occurrence of those risks has been minimized by several things. One is, I think, the magnitude of the existing resource base on the Slope, in addition to the 35Ts that we've been talking about. It's been minimized by the fiscal certainty offered in the contract, the provisions of the upstream contract, and the incentives proposed in PPT, which will encourage exploration, development. It will encourage new participants and reduce any -- any of the risk of not being able to meet -- have the revenues to meet our financial commitments.

And with that, I want to thank you.

And you want to take a break now and then --

COMMISSIONER CORBUS: I think we ought to --

COMMISSIONER GRIFFIN: -- entertain questions later?

COMMISSIONER CORBUS: Do we have a a --

COMMISSIONER GRIFFIN: Why don't we --

COMMISSIONER CORBUS: We've only got two questions so far. This is -- we're going to take a break and think about it, and we'll come back in 10 and get started. Thank you.

COMMISSIONER GRIFFIN: Why don't we do that, and I'll start with questions, talk about marketing, and then deal with questions at the end again.

Go ahead and let's take a break.

[Break]

COMMISSIONER CORBUS: Would we please take our seats so we can get started?

May we, please, resume?

Deputy Commissioner of Natural Resources, Ken Griffin, will now give a presentation on marketing Alaska's share of the gas.

COMMISSIONER GRIFFIN: Let's deal with the questions on capacity here first, and then I'll get into the marketing side of this.

I had a -- a number of questions on indemnity, the indemnification clause. Please explain the rationale behind the provisions on limiting damages and indemnification.

The rationale for that is -- you know, largely, this is -- this is a negotiated business agreement, and trying to balance the risk and the returns and the relationship between the various parties. The whole issue of marketing organizations having a relationship with one another or our -- or having any sort of an interaction between themselves is something that's very foreign in this business. And the idea that a producer marketer would be having any influence on a State marketer's capacity commitments or anything like that was something very difficult for them to -- to -- to swallow. Partly because it's foreign. Partly because they're very concerned about appearances, you know, collusion, that sort of thing, about creating risk and liability. The FERC requirements of -- of keeping -- keeping them separate. And I'm not sure I can speak to all the legal ramifications of that. But this -- this whole issue of having any influence on State capacity commitments, on acquiring State capacity or anything like that was something that was very difficult for them as marketers and businesses to accept. And the -- the indemnification and the -- the damages clauses were really necessary parts of obtaining these commitments from them.

One of the other things is -- when you're looking at the risk and the potential for damages and all, the capacity that the producers obtain on behalf of the State has to be tied to a property, and that protects the State from the standpoint that -- that we're getting capacity for deliveries from a specific property. It's not speculative, and it's -- it's not a wide open door or anything like that.

Why is the State indemnifying capacity losses and not the LLC?

The LLC is -- is essentially selling the capacity. And the marketers, the shippers are -- have the -- have the rights to that capacity. They -- they've purchased the rights to that capacity. It's a shipper commitment.

So, from the State's standpoint, it will be a commit- -- a commitment from the State gas marketer, gas shipper. It -- that commitment may initially be taken by the State, but once the marketing organization, which I'm going to talk about a little bit here in a -- in a moment, comes into being, they will be holding that commitment. And so it will be the State, as a gas owner and a shipper who is indemnifying the producers.

And -- is indemnity referring to State loss or the producer loss. What it's talking about, it is the State loss. And the -- the issue here is that the producers will be able to make their business decisions. They'll be able to make their business commitments, and the State will be responsible for our proportionate share of that. The producers will be responsible for their proportionate share of that.

And, again, I just fall back on the fact that this is a business -- negotiated business arrangement. These are commitments that we received from the producers, and as part of that, the indemnification and the damages clauses are all a part of -- of that negotiated arrangement.

Please give examples how excess capacity obligations could be satisfied.

That's really in 10.3, and I think there are probably two basic reasons they could be satisfied. One is the producer could go to a third party and simply purchase gas that they would ship on their capacity, and the proportionate share of that gas could then be shipped on our proportionate share of the capacity so -- so that we're both taking care of that excess capacity situation.

The second thing we could do is the producer could choose to post and sell that excess capacity to another shipper, and, along with that, they would sell our proportionate share of the excess capacity at the same time.

I've got a question on marketing which I'll save and answer afterwards here -- after the marketing presentation.

How do the commercial entities handle their capacity need differences? For -- for instance, Conoco needs 40 percent pipeline capacity of the gas coming out of KRU -- Kuparuk, but only 5 percent if it comes out of Point Thomson.

These companies will -- marketing companies, for one thing, operate at arm's length from each other. FERC has standards for how -- the Federal Energy Regulatory Commission has standards. And in Canada, it would be the -- their regulatory agencies have standards for how capacity is exchanged at arm's length.

And we can -- our FERC experts can talk about that a little bit more.

But these companies, as producers, will need to negotiate among themselves how they are going to make pipeline -- deliveries to the pipeline. They're going to need to do that way ahead of the open seasons so that they have a consensus at the north end of how they're going to be delivering gas from Prudhoe Bay or from Kuparuk or -- or from another field. And then based on that, those companies will need to go to the open season and bid.

It will -- at the -- at the -- it's -- it's a rather complicated thing, and I'm not sure I have all the answers for you right now. But these working interest owners at each field are going to have to deal with their delivery issues, and then their marketing organizations are going to need to take that information and deal with it as bidders at the open season, as -- as shippers and marketing organizations.

Article 10 really didn't try to address that. Article 10 was written to ensure a parity for the State regarding -- as these various things happen that, you know, we really can't predict right now. And whatever happens, the State has a proportional right to get our gas off the Slope. We're going to have a proportional responsibility for the -- the pipeline capacity.

Given the magnitude of the -- of the risk to the State, what consideration was given to moving the point of delivery from -- for the State's gas to Alberta?

This was one of the early commitments made in the negotiation, was to take our gas on the Slope and to take responsibility for transporting and -- and marketing our gas downstream. And so Article 10 was written with that assumption in mind and was negotiated with that -- that assumption in mind.

The taking the commitments upstream helped -- was part of the entire package of the contract, and it helped balance the costs and risks on the part of the producers and on our part to come up with a -- a contract that will help get a pipeline built.

I think that's all I have. So, you had one you wanted to deal with?

COMMISSIONER CORBUS: Ken, one question that came up, just to make it very clear. When we talk about a capacity commitment, what we're talking about is the State committing to ship its gas on the pipeline for a long period of time. And we would be committing to reserve, say, 20 percent of the -- of the pipeline for 20 to 30 years. And that means that the State would be committing somewhere between 3- to 400 million dollars a year that we will make -- that we will ship our gas. We don't know the exact magnitude of those numbers yet, because we don't know how much it's going to cost to build the project. But that will give you an idea of the order of magnitude of the commitment that the State would be making by taking a -- making a capacity commitment.

We had a question yesterday -- a followup question wanting to know that: May a party -- if a party withdraws from the contract after project sanction, where in the contract does it refer to the fact that the -- the rights under -- its -- its lease rights are forgiven or returned to the State?

And that is referred to in Article 31.6 of the contract that says that a party may withdraw from the contract after open season only if the participants and its affiliates have assigned or otherwise relinquished and hold no in -- interest in any midstream element in any North Slope lease or unit before the participant's notice of withdrawal.

And with that, we will turn it over to Ken Griffin who will talk about marketing.

COMMISSIONER GRIFFIN: You know, given that the State has agreed to take a royalty and our taxes in kind, contract terms were crafted to provide the State marketer with the information, with the transportation rights, the capacity commitments, and the gas to compete effectively with other marketers.

And it's important to recognize, you know, something on the 800 -- on the order of 800 to -- 800 million to 1 bcf a day is a significant amount of gas going into the marketplace. And some evidence of that is -- you know, the Governor has talked several times about people who have already approached -- companies that have already approached the State about our gas. There's a lot of interest out there. We are going to make a -- a significant difference in the -- in the marketplace.

And the other thing to realize is that the State enjoys tax advantages in the U.S. over other marketers. How we're going to transfer those tax advantages and just how, you know, they're going to work in our gas marketing en- -- entity is -- is unclear right now. But we do have those tax advantages, and we do want to make sure we capture them.

I want to talk about several forms of market risk, just to kind of give you an idea of the -- of the landscape here. First is what I labeled is gas price risk.

We've got two forms here. One is what we would call a short-term volatility. We see a lot that in -- in our oil prices as well as -- as gas, versus long-term price trends. And the effects of these in -- in marketing risk are very different.

The second is structural changes in the marketplace. The North American gas market is very different than it was in the days before Enron, and that -- that market structure is very different than the structure 15 years before.

So, we cannot assume that we know exactly the type of market we're going to be entering some ten years from now.

And geopolitical issues. More and more LNG is floating on the oceans. We're going to see that, I think, continue to grow. Most LNG is sold on very long-term contracts. We will probably see some changes to that as time goes on, particularly the time -- over the time frame we're talking about. And I think geopolitical issues probably will become more important there. Not like oil, because gas reserves around the world are not concentrated like the major oil reserves are, but, still, they will be issues, and they will affect our gas markets.

On the supply side, competition from other supplies, whether it's other gas supplies or simply other energy supplies that maybe displace gas in -- in certain areas.

And then our own reservoir and facility risk. And I think we can look at the magnitude of those risks simply by looking at the -- our own North Slope oil operations over the last 30 years. They're not perfect, but they're very close.

And something I call gas marketing risk. This is kind of the performance risk.

Competition from other marketers. Are we going to be able to get the value from our gas given the type of competition that we're going to be facing in the marketplace? Of course, this has to do with other competitors. It also has to do with the health of the marketplace that we're competing in.

And then, secondly, our own performance. Development of a marketing strategy that meets the needs of the State and then aligning a company -- organizing a company to -- to meet that strategy.

On the gas price risk side, of course, we have no direct control of prices. We're selling into a market, largely a commodity market, as I mentioned a few days ago. But the first major means of -- of mitigating this is by minimizing our construction costs.

Cost overruns will go into the tariff, raising the tariff and reducing the margins on our gas sales. And increasing the risk that -- in a -- some sort of really low price world we may not be able to cover our shipping commitments.

Gas sales contracting strategies or development of multiple strategies help minimize that risk. Financial hedging tools are commonly used by gas marketers.

And designing and planning for

access into multiple markets. Dr. Van Meurs has talked about the Alberta project and the Chicago project.

When you deliver into Chicago you're delivering into a huge natural gas hub -- distribution hub and market. But from AECO, you have access not only to that market, but markets all the way from New England to Oregon, across the North American continent.

These are all issues that should -- need to be designed and planned as -- as we go forward. And I just want to point out that we're talk -- we're talking about using the word "risk." These risks have opportunities. Marketing organ- -- gas marketing organizations exist because they make money for their companies.

There are opportunities here that can be captured based on the -- the strategy of that marketing organization.

On the supply side, you know, the MacKenzie Valley pipeline is often talked about in -- at the same time as our line. Very likely, they will come first. I don't see them as a significant supply risk, and partly because they're a quarter of the size of our line. They'll be coming in ahead of us, and because Canada has significant demands for their gas supplies that are -- and the oil sands is just one of the major growing ones right now.

LNG landings are -- are a gas supply risk. On the other side of it, the international appetite for LNG is growing.

Other North American developments. Just what they are, what they would be is -- is probably hard to explain, at least to the scale of -- of the Alaska gas pipeline, but mitigating that even more is what I refer to is the expectation theory of markets.

Markets see major gas deliveries coming long before they arrive. The North American market will adjust, and it will adapt to be ready for the Alaska gas pipeline long before we get there. And certainly the pipeline, when it starts up, will probably have some short-term price impacts on the North American market. But much of that will be taken up ahead of time, and -- and the -- and the impacts ought to be very short once we get to market.

The other thing is major capital

developments, capital intensive developments will be -- if they see the Alaska gasline coming, they will be making their investment decisions, their subsequent investment decisions knowing that the Alaska gasline is coming and that we will be affecting their market.

Alternative fuels and technological change. I did some manage- -- technology management work a while back. Some of the stuff I was reading at the time said that even if -- and this had to do with transportation, fuel cells and things like that. They said: Even if you find a technology that's going to displace gasoline in this case, it -- and we know it works -- it's going to take us 30 years to significantly penetrate the market because of the infrastructure that's attendant to all these things. And while that's talking about automobiles, I think it -- it applies here.

There is a huge infrastructure that has to be replaced to make any alternatives really viable.

We've all got electricity. We've all got natural gas to our homes. Other things are going to find it very difficult in the short-term to -- to replace those energy sources.

And -- and then I mentioned reservoir and facility risks. There are going to be multiple delivery points on the Slope. We have companies who know how to manage risk, know how to minimize the risk of supply interruptions, and this will be a major concern for them, as well as for us, as we move forward with North Slope gas developments.

The gas marketing risk, competition from other marketers. There -- this will affect our ability to attract the proper mix of buyers and contracts. They can affect our ability to obtain transport as needed.

We talked about the capacity article and how -- I think we've taken care of that. We will have issues if -- to get our gas out of Alberta if our project stops there. Certainly, our gas marketing organization is going to be preparing -- be prepared to deal with those issues, and at the same time, the companies are dealing with their own issues there.

The ability to attract a mix of buyers and contracts. I think we've already seen, there's a lot of interest in our gas and a lot of interest in having the State as -- as a supplier.

Strategy and alignment of this company is -- is important and is something that -- even right now in DNR we're working on.

Strategies can be value-adding or they can focus on risk aversion. We need to develop the -- the proper balance for the State of Alaska.

Organizational alignment then needs to be created to meet that strategy. And one of -- one of the options we have is -- the jargon is accretive business relationships. These are business relationships where the sum of the parts is more than just the two together. And it's joint ventures -- joint ventures or asset management arrangements where we have partners coming in, bringing assets to us, and the assets that the State are obviously providing are -- are a major gas supply.

The gas marketing role is actually multi-faceted. Managing capacity is going to be one of the needs. Managing daily variations, the -- and matching that to our capacity, matching it to our delivery requirements is part of the business.

Monitoring delivery forecasts and using the information that the producers have to manage our marketing organization not only for on a short-term basis but on a long-term.

Managing transportation capacity out of Alberta, I mentioned that already.

Preparing for and participating in our open seasons.

And then selling the gas, whether it's in-state or exporting it to the North American market.

And then managing our mix of sales contracts, our financial tools, and the markets that we're delivering into to minimize our risk and to maximize returns in accordance with the policy, the strategy developed for this -- for this organization.

DNR has identified several gas marketing options. We've held preliminary discussions with several partners -- potential partners.

More extensive consultant input is needed. We need to also meet in more detail and -- and investigate the various business --

types of business arrangements and the various potential partners in -- in much more detail. Definitive proposals ultimately need to be solicited and evaluated.

I mentioned the tax issues. Those need to be explored in -- in much more detail. We've got tax issues in Canada, too. How we manage those is -- is probably a major question.

And then we're getting into the financial issues. The capacity commitment is a major -- a major dollar item, as Commissioner Corbus mentioned.

That's going to affect the financial health of either the State of Alaska or of this gas marketing organization. And that's going to affect the way major end users look at us as a potential supplier. Protecting the financial health and the credit health of this marketing organization is -- is, again, a major issue.

Our intention is next year to present the Legislature with a plan for -- for this -- for this company and begin to get the board and -- and the leadership of it established.

Some of the gas marketing options I -- I mentioned a minute ago kind of from the -- the simplest, easiest to a more complex. We could simply have early long-term gas sales. Sell it upfront to -- to an end user or to buyers. We could have spot sales at the first market, simply dump our gas into the Alberta market, dump it into the Chicago market, and -- and take the -- the spot price. Some major marketers, in fact, do that.

We could have firm contracting for the gas sales and the opportunity to have a mix of contracts, going to a mix of users, a mix of terms and balance risks somewhat that way.

And then making -- taking advantage of the expertise of others. Contracting with asset managers, entering into joint ventures with companies that have complementary assets to ours.

All of these options, we don't have -- these are questions. We don't have answers right now. These are things that need to be evaluated, and we need to work all these answers out over the next few months.

Some of the issues, I addressed some of this a little bit before. The policy issues, many of these will be things that ultimately you will need to decide.

Identifying the type of entity, the type of structure that's appropriate. Identifying the -- establishing the protocols and the authorities. Balancing the -- the strategy to best meet the goals of -- of the state.

The financial issues, funding this entity, the credit support of this entity.

Business issues such as a strategy. And -- and it's going to need to be a strategy and a -- in a -- a business arrangement that can serve the State effectively, even as the market changes over time. You know, we're -- we're talking about company that will begin to -- to truly see revenues for the State a decade from now. They -- they will be serving the State for 30, 40 years, at least, afterwards.

We -- we need an entity that is flexible over all the changes we're liable to see during that time.

Legal issues and tax issues, I think I've addressed these already. All of these need to be weighed over the next few months.

And that's really what I have right

now to talk about on the marketing side.

The only thing other I would say is that these are issues that companies deal with successfully day in and day out every day. The State is fully capable of putting together the entity we need to serve our needs in -- in the gas marketing arena.

And with that, should we take a short break and let people get questions together? And then I'll come up and deal with that. And I think we're done for the morning with that.

So, ten minutes, Bill?

COMMISSIONER CORBUS: Yes, sir.

COMMISSIONER GRIFFIN: Ten minutes.

[Break]

COMMISSIONER CORBUS: May we please take our seats.

We'll now reconvene. We only have one question on marketing.

I'm going to turn it over to Ken Griffin.

Please, if you have any other questions, send them up.

COMMISSIONER GRIFFIN: This was

handed earlier. Given that the State of Alaska's lease documents require the leaseholder to produce, market, and pay the hire of for our gas, what is the advantage to the State if we take the risk and expense of marketing our gas? What is the difference in revenue received by the State if we market our gas ourselves?

The -- the main answer, I think, to this question is that the hire of -- of -- our gas is not worth anything as long as that gas is in the ground. And the -- the biggest thing we receive from making these commitments is that we have a proposed contract that will enable us to ultimately get our gas to market and begin to enjoy the revenues associated with this resource.

The second part of the question, the different -- what is the difference in revenue received by the State if we market our gas ourselves?

Marketing organizations -- gas marketing organizations come in -- in very, very different flavors, even the major marketing organizations, the Exxons, the BPs, the Conocos, the Shells all have -- there's a spectrum of strategies there.

Some companies are simply price takers. Major gas marketing companies are simply price takers. They deliver their gas into a market, and they take what they receive.

Others have extensive gas marketing organizations and forecasting organizations that create incremental value for their -- for their companies.

Some of these organizations market many times the amount of gas that their company produces. And they market those additional volumes of gas because there's incremental value to be captured there. And, you know, those are -- those are kind of the end points of the spectrum that the State needs to take a look at and figure out: What do we want our marketing organization to do? What are we willing to fund and organize and -- and -- and put together organizationally? What sort of risks are we willing to assume there? And then what sort of returns do we expect as a result?

And I think that's all we have.

I'll be around here. More than happy to speak to anybody who needs to take a few minutes.

COMMISSIONER CORBUS: Thank you, Ken.

This afternoon, we're going to have presentations by Bob Loeffler on FERC permitting, the EIS process, project sanction, and then we're going to start in on the explanation of the contract.

We are adjourned until 2:00 p.m. this afternoon.

Thank you.

[Lunch break]

COMMISSIONER CORBUS: For everybody's information, our featured speaker, Bob Loeffler, has just arrived from the airport, and we'll be starting up in about five minutes.

Good afternoon. This afternoon, we have presentations on FERC permitting, the EIS process, project sanction, and then we're going to start going through the contract provisions.

With me at the front here is from the Attorney General's office, of course, Attorney General David Marquez, as well as Assistant Attorney General Rich Burnham.

Attorney General Marquez is going to introduce our speaker.

ATTORNEY GENERAL MARQUEZ: Good afternoon. Is this on?

Good afternoon.

I very much appreciate your patience. Mr. Loeffler just flew in from Washington, D.C., just arrived, and was a little delayed. I'm sure you all can appreciate delays in getting into Juneau, and we appreciate your patience.

I'm very pleased to introduce Mr. Loeffler this afternoon. He's a senior partner in the Washington, D.C., office of Morrison & Foerster. Mr. Loeffler was a founder of the Washington office of that firm and served as its managing partner for most of its first decade.

He has represented a variety of energy clients, both private and public, in Federal Energy Regulatory Commission or FERC, and in State administrative proceedings. He is listed by Chambers, which is a Who's Who of lawyers, as a leading energy lawyer. He was a director of the Energy Bar Association and for two terms was chair of the administrative law section of the District of Columbia Bar.

For 30 years, Mr. Loeffler has been the State of Alaska's lead counsel on federal energy regulatory matters and oil industry matters. Mr. Loeffler has represented the State on pipeline and energy matters for more than three decades. From 1974 to 1982, he represented the State in congressional and executive branch process on the ANGTS, the Alaska Natural Gas Transportation System, matter, which was the first effort at monetizing our natural gas resources. He was involved in all of the State's oil pipeline litigation and in aspects of its royalty and tax cases.

Mr. Loeffler graduated magna cum laude from Harvard in 1965 and cum laude from Columbia Law School in 1968, where he was an editor of the Columbia Law Review, as well as chairman of the Board of Student Affairs. After graduation, Mr. Loeffler served as a law clerk to Senior Circuit Judge Harold R. Medina of the U.S. Court of Appeals for the Second Circuit.

Mr. Loeffler and his firm are under contract to the Alaska Department of Law to assist us in the negotiations of this contract. Of all the members of the legal team, Mr. Loeffler has been the lawyer who has been involved most consistently across all of the provisions of the agreement.

It's my pleasure to introduce Mr. Loeffler.

[Applause]

MR. LOEFFLER: That was a very generous introduction. I hope I live up to it.

As Dave said, I spent eight years as a young lawyer working on the first incarnation of the gas pipeline, and now, as a not so young lawyer, I hope to see it come to fruition.

I want to give you some points of reference or context before we get into the PowerPoint.

I am not going to discuss the process issues that might arise with regard to the old permits for the ANGTS. What I'm talking about today is the project that is before you as part of the Stranded Gas Act proposed contract and the process that would apply to that.

I should point out that we do discuss some of those issues in the fiscal interest finding when we talk about the Canadian issues.

I also should point out that the FERC process is a combination of both old and new. There's a preexisting Natural Gas Act and then grafted on top of that are the special provisions of the 2004 legislation, and we'll get into those.

As I think most of you know, the FERC and all national authorities are very much committed to seeing a successful Alaska gas pipeline.

The evidence of that is severalfold. You saw all of the Commissioners come up to Alaska in December, 2004. That's never happened at any state before. You could see it really in the result in orders 2005 and 2005(a), and I can tell you that from my periodic visits to the FERC and to the Commissioners, they're very interested in seeing a project, seeing an application before them.

I could also say that as committed as they are, they'll still do their job under the law, and they have process and standards they have to apply. But they're ready to go.

I am going to talk about the FERC

process, but I want to point out that there are many other federal permits involved that will be needed for the project. Clean water permits, rights of way from the Department of Interior, and for that matter, from the State, clean air permits. And FERC has been given a lead role with regard to the assembly of those permits. There's also will be a federal coordinator, and I'll talk about that in some detail.

Another point is that there is a parallel process in Canada. For this project it would be before the National Energy Board. That also is described in the Fiscal Interest Finding report, and, in fact, there's a layout of the next steps in that report at pages 217 to 239.

So, that is the sort of opening set of remarks I want to make.

I want to point out also, and I don't know if this has been placed on the State website yet, but it will be. On May 10th, we received a project summary -- a revised project summary for the project. And the project summary, unlike the project summary that is in the draft fiscal interest finding, has years associated, based on an assumption of when the stranded gas contract would be approved. And you can look in there and see in a success case, when an application would go to the FERC, when the open season would occur, and other things like that.

I don't think it made it into the PowerPoint because there were just travel and delay problems, but we will get that out.

Well, let me see if I can do this.

Very good.

I'm going to -- I'm going to emphasize some very, very basic points, and I apologize to part of the audience, but sometimes we forget, really, what FERC does.

The keys to the kingdom are the Certificate of Public Convenience and Necessity that the FERC grants. No interstate gas pipeline can be constructed or operated without this certificate, and FERC's authority in this respect is exclusive and paramount. It's a very different case for an interstate oil pipeline, and I will explain the differences in a couple of slides.

But the Natural Gas Act says: No natural gas company can engage, essentially, in the transportation of natural gas in interstate commerce without this certificate from the FERC.

The other point is, you cannot even undertake the construction of facilities for a pipeline without permission from the FERC.

So, it's a hurdle that must be passed, and it's a very, very substantial hurdle.

I said FERC does not regulate oil pipelines in the same way, and I've run into this over and over, and sometimes even the courts get it wrong.

If you want to build an oil pipeline like TAPS or any of the other Lower 48 oil pipelines, you do not go to FERC for this comprehensive certificate. They do not authorize the construction. They do not authorize the facilities. They don't regulate the operation of the oil pipeline.

Regulation of oil pipelines is a vestige of the Interstate Commerce Act, and all FERC does is regulate interstate rates on an oil pipeline. So, if you reel back to what happened when TAPS was being contemplated, you'll find that, really, the driving authority or permit was the Department of Interior, which granted a right-of-way for TAPS, because FERC didn't have any role until the oil pipeline was in operation and then the issue of the rates came before it.

By the same token, on TAPS there is dual jurisdiction of the RCA and the FERC on rates. And it's a big difference, because there's a Supreme Court case that says for a gasline the FERC regulates not only the rate for the gas that's going out of state, but the rate for gas that's going in-state on the trunk line, on the mainline, until it leaves that line. In our case, the RCA will take over at that point.

Another difference is that on an interstate gasline the holder of the Certificate of Public Convenience and Necessity has the right of eminent domain. It can actually condemn private land for its right of way, and in a number of cases, it has condemned municipal land. I think it's untested on State land, but I'm not sure of that.

Now, that's a ultimate sanction. If you can't get your right of way, you could resort to condemnation. No such right exists under the Interstate Commerce Act for oil pipelines. It's another illustration of the difference between the regulation of oil and gas pipelines.

This next chart is really, with due credit, something FERC puts out, and it's not entirely accurate for what will happen here.

In a number of cases, proposed gas pipeline projects will hold open seasons, even nonbinding open season or open seasons for expansion, just to see if anyone is interested.

In the case of our pipeline, it will be different.  Because we know people are interested.  But it's still -- the open season process is like an auction process in which bidders show up and say how much capacity they'll take on the pipeline, and the pipeline says whether the terms are acceptable.

But in the normal process, the garden variety gas pipeline, if there is such a thing, this is the process that's followed.  And you can see that the issue of crossing lands is something they expect the pipeline to face before you come to FERC, start easement negotiations, hold public meetings, do resource reports which go into the environmental impact analysis, and then file.

Again -- and this is material that was put together by the Lukens Energy Group for an LB&A hearing in June, 2004. I'm going to spin through this, but this is the normal process.

The open season process is, you know, designed to get people interested in the pipeline to show up so there are typical communication requirements. And then I made reference to this sort of back and forth that goes on between the pipeline and the prospective shippers. And the shippers do not want to make an unlimited contractual commitment on any pipeline unless they know what they're getting. They want to know when the project will be delivered, what the tariff looks like. And the other side of it, the pipeline usually reserves the right to cancel the project if economic conditions turn out differently.

So what you have is a precedent agreement. And that's a conditional deal between the pipeline project and a proposed shipper. And it will set out, as it says, the pipeline's agreement to construct facilities; receipt and delivery; the term, is it five years, ten years, 25 years, whatever; rates; right of way on acceptable terms.

The pipeline, see, comes back and says: We need an approval on issuance of a certificate by FERC by a certain date and with consistent conditions. We need our -- both boards of directors have to approve. There has to be credit requirements established.

So it's a tug of war between the pipeline, which wants to get as much financial security as it can from the shippers and the shippers who want to be sure they're get -- committing to a project that's going to deliver on a schedule that serves their needs.

I think we can skip this. A number of you have seen it before, but it -- the termination rights are worth, when you have a spare moment, looking at. Because there are termination rights typically on both sides -- obviously, if the facilities have not been commenced by a certain date; if you don't get a timely regulatory approval; if a shipper does not receive board of director approval.

And the pipeline says, Look, if FERC comes out with a certificate that we don't like, it's materially different, we reserve the right to cancel the project. If the pipeline sponsors believe the project isn't viable anymore, that's another thing, et cetera, et cetera.

In some cases there's a termination fee. Now, you would logically ask: What do we know is going to happen on this pipeline? And the answer is: Not very much. Because these conditions will be established by the project before the open season. And what happens for this one is a little different, because, as I know members of the Legislature know, FERC was required by statute to have rules for this open season.

Normally the open season process is a complaint process. If you're a participant in the open season and you don't like what's happening, you go running to FERC either before or after the open season and say, "I wasn't treated fairly, I was discriminated against." That's a legal term in this case.

But what happened here, Congress said, FERC, you go out and you adopt open season requirements for this pipeline. And I think we all remember the hearing we had up here in

December, 2004. FERC came out with, really, a very good set of regulations from our point of view.

First of all, the notice that gives shippers all the information they need about the open season has to be submitted to FERC before the open season. So, there will be some prior review by FERC, and that's an opportunity to complain about things that seem unfair or don't comply with the regulations.

And then 30 -- the notice has to give shippers -- potential shippers 30 days' time before the open season opens, and the idea is people need time to prepare. That becomes a very important issue for potential intrastate shippers. Because one of the things we all successfully achieved is the open season notice will have to have information about a proposed intrastate rate.

So, intrastate shippers have to be prepared to participate in the open season. That's the best way for them to get capacity. If they're not prepared, then they are in a sort of Johnny-come-lately position, and that's not a favorable place to be.

Now, I'm not going to bore you with all the details, but I had copied into the PowerPoint these core of the regulations, and I want to point out a couple things.

If you look at (c) (1), they have to in the open -- the pipeline has to, in the open season notice, identify in-state delivery points. Those in-state delivery points are supposed to be the product of a study that either the pipeline has done before the open season or the State has done and they have adopted. But they're supposed to designate at the open season -- in the open season notice delivery points for intrastate service. There also -- I have to address, if you look at the end of No. (2), what the capability of expansion of the pipeline is. Again, a very important issue of -- that we all pressed very hard in the open season rule-making. Because that expansion capability is very important to people who explore and want to be sure they're able to get on that pipeline.

Lots of detail. Proposed tariff estimated costs of service. And look at No. 8 again, on the in-state theme. Based on the study, there must be an estimated transportation rate for in-state deliveries. And we considered this very important, the last sentence. That's a rate for the cost of making those deliveries inside Alaska, and it should not, by the regulation, reflect the costs of going outside Alaska. So, it's a -- should be a favorable rate to in-state deliveries. And that is a requirement of law, which is very important, because it even goes beyond the contract. All these requirements have to be satisfied.

Another one, which could bite both ways, is the creditworthiness standard. The FERC allows pipelines to make sure that shippers are creditworthy, that they're not going to default on their commitments.

But that gives some discretion to the pipeline to set a standard that may be harder for smaller companies or less financially viable -- well, not viable, but less financially strong participants to satisfy. So, again, there are some very loose rules at FERC about what a good creditworthy standard is, but we have to look at that when it actually comes out.

No. 14 and 15 are, again, in some ways the heart of the game. Think of yourself as a pipeline, as hard as that may be. But you -- you've got all these people coming in and offering to take capacity. Are they going to come in, and are they going to take capacity for five years, 15 years, 25 years, or 20?

The pipeline, we expect, will want long-term capacity bids that will be matched up in some way with its financing. Fifteen, 20, 25 years is the range. That's as good as we can do today.

But suppose you're a small in-state shipper who wants to commit for five years of capacity or ten years? Your bid in normal conditions will not look as strong, because what they do is take the length of the bid and they value that. You're willing to sign up for, hypothetically, 15 years of capacity at, let's say, $1.50 or something. You can total that up, bring it down to a net present value; it's going to be a lot more money than a smaller bid or a shorter bid.

There's potential for discrimination, on the other hand. There's potential not to satisfy the pipeline's financial requirements.

The pipeline takes these first proceeding agreements and then FT commitments to the bank, and that's how a pipeline is financed. They are -- you've got creditworthy shippers willing to sign up for service conditionally for 15, 20, 25 years. That's the core of how a pipeline is financed.

You're going to hear more about that later in the week. But there's still room around the edges for the smaller shippers.

On the other hand, if those long-term commitments go too long, beyond the reasonable financing needs of the project, you have the possibility of locking up capacity that would be to the benefit of the largest and the most economically successful shippers. So FERC is going to look at that issue, too.

There is room for accommodating both in-state and out of state commitments here, but you -- when you think about what the core financial obligation is, it's going to be met by those backbone shippers, big guys, long-term, who have -- are making a huge financial commitment.

No. 21, again, is something that was talked about a lot in the rule-making, which is you want to make sure that no information is passed advantageously to affiliates to the disadvantage of people who are not affiliated with the owners of the pipe. And FERC has rules on that, but they strengthened the rules and required an affirmative statement that the pipeline had complied and had satisfied those requirements.

If I read the chart, the success case correctly in the chart that I gave you, I referenced to you, I think that the start of the open season process could be -- no guarantee here, but could be as early as a year and a half from now. There are a lot of things that have to happen. Because to fill out all that detailed information, there has to be front-end engineering and design, fieldwork, and things like that.

My experience, unfortunately, with the Alaska gas pipeline the first time around is schedules slip. But let's hope this one is better. I actually promised someone in the Governor's office that I would do a Mexican hat dance if we have the open season in a year and a half. Don't take that down.

The filing process at the FERC, and now I'm talking about the process for filing an application, is also involved. But in the last few years, the FERC has adopted a sort of prefiling process, which I think the sponsors have informally indicated they're going to participate in.

You go to the FERC before you're ready to file an application. You work out what they want in terms of environmental studies, other sort of technical reports, and you get an advanced look at everything, and that speeds the ultimate result.

Part of the obligation, per the FERC regulations, is when you do that, you identify participants who are potentially affected. You go out and you identify people in the communities along the route, industry along the route, and you start talking to people. So there is a -- something of a public process that you commit to as part of this.

The standard pipeline, this will cause an environmental impact statement to come out maybe five to seven months earlier than normal. And that's a big advantage. In some pipelines recently in the Western United States have gone through the FERC in remarkably short time because of this pre-filing process.

Again, we're in standard law, not special Alaska law here.

But when you come in -- when one of these applications comes in, it's not like an application for a driver's license or a passport. It is a truck that arrives at the FERC. The application is many volumes and really describes the project in great detail, the financing or proposed financing, the tariff in detail, the cost of the project. And I've just -- you can spin your eyes through this. There's an environmental report, gas supply, flow diagrams. And it's divided into pieces, and then markets and things like that are processed by the FERC.

The tariff is supposed to be -- or proposed tariff laid out is part of the project, and that will be worth studying, too.

On the tariff, you have to explain what it is. Is it a cost of service? Is it negotiated? What are the competitive factors? What studies have been made? So there's quite a bit to chew up -- chew into when you get it.

Congress modified this because people said FERC could take a very long time, as it has in the past. Again, referencing my early lawyer experience, the comparative hearing on the ANGTS, we had 18 months of continuous hearing before Congress stepped in, and it sort of got monotonous going down to the FERC every day for 18 months and waiting your turn in line of 40 parties to cross-examine, and it was that -- and I think that's a process no one wants to repeat.

So, what Congress did is said, Step one, project files a complete application. And that's a buzz word at FERC. The prefiling process means that you've gone down, and you sort of know what FERC wants, so you shouldn't have problems filing an incomplete application. But the word "complete" in the statute gives the FERC the power to say it's incomplete so the clock doesn't start running. Again, that should not happen, but it has happened historically.

The next step is the draft environmental impact statement has to be completed by FERC 12 months later. And then it gets really tight. The final impact statement has to go six months after the draft. And FERC has to be done and either issue or deny -- I put issue, because that's the result we want -- the certificate two months after that.

What that means is the FERC process, by direction of Congress, is 20 months long. That's pretty fast. It's really amazingly fast for a project this size.

So there'll be parallel tracks at FERC. One thing that will be happening is the impact statement will be assembled and put out for comment. The other is that whatever hearing process the FERC will have will occur within that same 20 months. And it's not only the hearing process, it's hearing, briefing, and anything that goes to the Commission. The Commission itself has to be done within 20 months.

And so that's quite a tight schedule. Everyone's familiar with an impact statement. There have been impact statements done in the past for both the pipeline and the conditioning plant, and they study alternatives and options. They describe the impacts. And sometimes they have a very dramatic result. In fact, the Northwest project came out of the suggestion in the impact statement years ago that the Alaska Highway route was the preferred route. At the time, the only two projects that were first before the Commission were an LNG project, the El Paso project, and the Arctic gas project across the wildlife range. The environmental impact statement suggested maybe the highway project was the preferred route. And, in fact, Northwest filed late and got into the process based on that environmental issue and succeeded ultimately.

I've said, and my understanding, at least, is that from talking to people at FERC and in the project that they committed to the prefiling process. For the FERC, it's important just in a bureaucratic sense to be able to get the resources lined up, get the budget from Congress. And the date that FERC is looking to is when it really has to get activated to do something. And they've seen statements in the Alaska press that suggest X or Y, and they get excited, and then I go down and explain really what's going to happen.

The public process at the FERC is likely to be quite dynamic. Really, FERC has very loose standing requirements, and anyone can come in and assert their rights or complain about the inadequacy of the project or that they have a superior project.  So, if you think about the universe of people who might show up, it could be the Port Authority project; it could be holders of the old rights under ANGTS; it could be either happy shippers, protecting what they got in the open season, or unhappy shippers that didn't; end users of gas; governments; California Public Utility Commission; New York Public Service Commission last time; Lower 48 pipelines through which this gasline may flow.

And to illustrate, again, from history how many participants, the service list in the ANGTS case had, I think, 196 different intervenors.  And on the first day of the hearing, it took a day and a half for the lawyers to stand up and say who they were representing, which I thought was a grand waste of time, as well client money.

The end of the process, when FERC comes out with the certificate, they just don't say, Here's your certificate, go build the pipeline.  They'll have pages of conditions about construction.  They'll have their own authorized officer. There'll be a notice to proceed process. And as a general condition, they say usually you have to commence construction by X, and you have to complete construction within, usually, three years. Anything that I say is a general condition. It will be tailored especially for this project.

The pipeline, when it receives this certificate, will look at it and will say, Gee, I like it, I can live with the conditions, or I don't like it and I can't live with the conditions. I -- and there's a process of re-hearing. You could go back and ask the conditions be clarified or that conditions be eliminated or removed.

And then you cannot force the project to take the certificate. They look at the conditions, and they make a decision whether they want to put their private capital into this project under those conditions.

But the certificate and its conditions are just a very critical point in the timeline. I reference the fiscal interest finding at 2:30. There's a list based on the current LLC discussions of what the LLC will want to decide before it will authorize going ahead with the project. And one of them is the FERC certificate. One is: Do they have all the other governmental approvals they need? Do they have a Canadian certificate or approval? And do they have a financing plan? So, I urge you to look carefully at the -- page 230 of the fiscal interest findings.

Unhappy parties can take the FERC to court, but Congress saw to that, too, and gave exclusive jurisdiction to review any challenges to what the FERC does in the U.S. Court of Appeals for the District of Columbia Circuit. The scope of review is limited, although the language is somewhat curious. And the court must expedite this over -- must just expedite it.

A couple points. One an observation. This -- I believe this expedited review applied to the one challenge that was made to the open season order. That challenge was made, roughly, in July, 2005. The FERC -- excuse me, the U.S. Court of Appeals set its briefing schedule a month ago. The briefing schedule extends through September. So either they didn't read the statute or they're the Court of Appeals.

I think in the case of an actual challenge to the certificate they would give it much faster review. The old ANGTS law had a 90-day requirement, 90-day filing to decision, and there were about four or five challenges, the State brought one. And they -- they were decided in 90 days, so they can act quickly if they want to.

What can be challenged? The constitutionality of the 2004 legislation or any act or permit under the authority of this statute, the adequacy of the environmental impact statement, or the validity of any final order. And I find that curious. I haven't seen that in any other statute: The validity of the final order. Usually, is it unjust, unreasonable, beyond the scope of authority? But they used "validity," and the court will figure out what that means. But the idea is to narrow the scope of review.

At the end of the process is project sanction which, again, is defined or explained in the fiscal interest finding. And I think it's at -- maybe at 238. Check me on that. But that's when the real commitment is made to go ahead with the project. That's when there's enough definition to go ahead with the project. You've got the FERC certificate with conditions, you know what's happening in Canada, you've got a financing plan, you've got shipper commitments. And that's when the companies and the LLC will vote, this -- commit to spending whatever it will be, 15, $20 billion. And that's sort of the final make or break date. And that's, obviously, a very, very serious point of commitment, and from there, the project should go rolling.

So, when you look at various parts of our contract, such as the work commitments and the standard of diligence until project sanction, the State's push was to get -- get it to the point of project sanction, and that's go or don't go at that point.

That is what I intended to say about the FERC process.

Bill, do you want to take questions on FERC process now?

COMMISSIONER CORBUS: You take them here.

We have four questions on FERC which will -- some of which came in at earlier meetings. If you'd read the question, Bob.

MR. LOEFFLER: Sure.

I'll take the most legible one first. Regarding potential protests during public process at the FERC, how does the fact that in our project the producers hold the leases -- leases and refuse to sell define the outcome for competing proposals?

Well, that is, as you know, the subject of litigation, but FERC will decide, ultimately, whether the project is in the public interest. Is it viable as -- is it in the public interest? Does it serve the public interest?

I expect that people who feel that they are disadvantaged for competitive reasons, including antitrust reasons, will bring those complaints to the FERC if they haven't been resolved first.

The FERC does not itself enforce the antitrust laws, but it does decide or have the power to decide whether conditions exist that are antithetical to the antitrust laws. So it takes into consideration or should take into consideration antitrust or competitive concerns.

It has originally, long before this

project, adopted open season requirements because people were concerned about the fact that pipelines had affiliates and the affiliates were getting preferred access to space on the pipeline. That's where the whole open season idea came from, and as I've said, that was loaded with a lot more detail for this project.

But unless someone can make a successful case at the FERC that there is some serious antitrust problem with the arrangements that exist, despite the fact that there are open season requirements, unless they can make that case, a competing project would have a very difficult time.

A competing project would have the right to make its case to complain either that there's a violation of the antitrust laws, but they'd have to prove that or provide substantial proof, or they could even make the case that their project is a better project; and, therefore, the project before the FERC should be denied in favor of the better project. Or they could argue that something should be done to change the proposed project to accommodate or solve the -- their particular problem.

For example, if someone had a small LNG project, they might come to the FERC and want some arrangement that would accommodate -- or a better arrangement that would accommodate an LNG project. And FERC would have to decide what the right public interest balance is. There's no question they have the right to make their case at the FERC, No. 1. No. 2, that they can raise competition and other issues. But the fact that they don't have the gas, unless there's some real competitive problem, is going to be a major obstacle, because FERC likes to leave it to the market. In the last ten years or so, that's become a dominant theme. Who can line up shippers? Who can get financing? Who can build the project?

Since I didn't know who asked that, I --

Next question: Since most North American gas is sold as a commodity not why -- why not have a common carrier rather than a contract carrier gas pipeline?

I guess you could direct that to Congress.

The open season requirements are

philosophically in the same direction as common carriage. And, indeed, when you went first to the unbundling of the commodity gas from the transportation service and forced it into two affiliates, you were moving sort of in that direction. But the difference -- technical difference on contract carriage, if a shipper comes along late, let's just say later in the process, and there's not enough capacity to accommodate the lately arrived shipper, under a common carriage scheme, you would prorate the capacity among the new and the old. Under contract carriage, the people who get the capacity first have superior rights.

And I would think there's a connection in the minds of the regulatory people between the idea of letting the market decide what project can be viable and the way modern pipelines line up the shipper commitments. And if you're going to disturb those shipper commitments, you're sort of interfering with the market process.

But Congress has not seen fit to make them common carriers, and FERC has not done more than I've said. It tries -- it tries to avoid discrimination, because that's its statutory charge under the Natural Gas Act, but it does not impose common carriage.

Are the oil companies still challenging some of the provisions won by the State in rule 2005?

There is a court challenge. It is by the oil companies. It pertains to one aspect of the rule. I recollect what the one aspect is, FERC said you can come in with your application, but if we're not satisfied that there's sufficient expansion capacity for the future, we can order physical changes in the project to accommodate future shippers.

The oil companies have seen fit to challenge that. My prediction is that it's a loser. I believe it's a loser because, as long as I can remember, upheld by the Supreme Court, FERC has been given the right to take a project that comes into it and make changes to it. That's part of its job. If there's something that doesn't serve the public interest, it can change design constraints, engineering constraints. It can change tariffs. That's the process at the FERC. That's the game at the

FERC. And there's court authority upholding that.

I think from the sponsors' point of view, they're worried that they'll spend several hundred million dollars getting ready, getting to the FERC on engineering and field studies, and then they'll have a design change ordered by the FERC which will cause them to lose time and money because they have to re-engineer their project. But as I understand the law, and I'm not a prophet here, but the law is distinctly against the companies, but they've picked that one issue and gone on.

Next: It is suggested that we take comfort in the 2000 FERC regulations, yet the terms of the contract seem to weaken these protections. The presumption of rolled-in rate setting seems to have been taken back to an incremental methodology. Also, the producers are currently challenging part of the FERC rules in court.

Well, to answer the second half. I do not think the assumption of the first question is correct. There are -- nothing in the contract is meant to disturb FERC's requirements in terms of a mandatory expansion and how they would address it. There is some language in one of the three rights of expansion. And -- and I'm jumping ahead of my next talk. But what you have in the contract are three -- what you have in the law and the contract combined are three different ways the pipeline can be expanded. One way is voluntary expansion. The pipeline decides it's in its business interest to expand. Perhaps shippers come to it and say they've got big new finds and they want space and there's not enough space on it. So that's just voluntary. That's at the discretion of the project.

In the 2004 legislation, FERC was given, for the first time, the right to order an expansion. And then the -- in the contract, on top of that, we've created a right to State-initiated expansion, which I'll save for later. And I don't believe that we've weakened those protections, but I'll look at that again in -- when I get to expansion tomorrow.

In Monday's session, my partner, Brad Lui, quoted from 18 CFR Section 157.37, in which the FERC stated that: In considering any application they would consider the extent which the proposed project had been designed to accommodate the needs of shippers who make conforming bids in the open season and might require changes in project design necessary to promote competition and offer reasonable opportunity for access to the project.

Since this section of the regulations is the subject of the pending producer appeal from FERC's orders and may be eliminated if the producers win that appeal, shouldn't the fact that this appeal was pending have been disclosed to us in the slide?

I disclose it now. I mean, I'm sorry if it wasn't in the slide, but I didn't -- I -- Brad and I -- I was flying back as he was flying out, and I didn't have a chance to look at that. We're not hiding anything, as I've said. I think that's a low likelihood of success.

Those are the questions we have.

You have another one?

COMMISSIONER CORBUS: We have about ten.

MR. LOEFFLER: Okay.

It's like a quiz show.

I indicated that the partners have

indicated they will participate informally in the prefiling process. What exactly does that mean? Is it a commitment made under the contract? Will an informal process really save time?

It is -- I have to check the contract on that. I know we talked about it. I don't know if it's a commitment made in the contract. I'll just have to check that.

I was told by the FERC people that they are already talking to the producers, and I've heard the same thing inside the contract negotiations. And I will check whether we have embodied that in the contract or not.

But that's my information, what does it mean. And that's what it means.

Would an informal process really save time?

The experience of the industry is that it does save time, and I don't see any reason why it would add time.

What is the difference in the level of protection for the State between tariff rates versus negotiated rates?

Well, the way negotiated rates -- the way rates go is you can have -- you always --

the pipeline is always required to offer a recourse rate, which is a rate based on the cost of service in the traditional way. And the theory of the FERC has been that if you don't like what's being offered to you in negotiation, you can go to the recourse rate. The -- it sort of depends on the deal that's offered. Those negotiations haven't occurred. The advantage of a negotiated rate is that you can have it designed to meet your needs a little bit. Or a lot.

The disadvantage of a negotiated rate is you sometimes have to give up your right to protest the deal that you negotiated.

So, there's the tradeoff. You negotiate a rate that you like, but it's common to limit or preclude challenges to the rate you negotiated by the party who signed the deal. So that's the difference.

Mr. Loeffler discussed FERC regulation on the basis -- rather, excuse me, on the midstream line, the so-called mainline under the contract. What about FERC oversight of the GTP or the feeder lines?

Is there a possibility that FERC

will not regulate these upstream facilities?

Please explain 8.1, 8.3 RCA exclusive indemnification.

I'm going to take part of this, and I am going to spend some time. I want to go to 8.1 and 8.3, walk you through the RCA clause.

I think there is a very sound basis for believing the GTP will be a regulated facility. I'll start with the fact that Order 2005 and 2005(a) impose open season requirements on the GTP, on the treatment plant. That was a point we made on our petition for rehearing, and when I talked to the FERC staff, they said, of course, it's just another piece of pipe as far as they're concerned. And they extended their jurisdiction to it in the important open season requirements.

We've analyzed, as best we can, the -- a gas transmission pipeline's upstream of the GTP in the mainline and looked at FERC precedent and talked to Lukens Energy about Lower 48 precedent. But for everything we know today, those are part of the system. They are not -- do not constitute any definition of a gathering line. FERC's jurisdiction excludes gathering lines. And we feel pretty solid that they will be regulated by the FERC, and that's the expectation that the contract states.

I'm going to take the RCA clause, which takes a fair amount of time tomorrow, so I'm going to defer the rest of that.

Next: FERC was mandated by Congress to make provisions for expansion of the pipeline to accommodate future needs, and they came out with a final rule on 2/9/05 establishing requirements governing open seasons for expansion capacity. 8 point -- Article 8.7(a)4(h), page 86 says, Article 8.7 is effective unless FERC determines that any of its provisions are contrary to law. If a FERC issues a certificate on a basis different than the expansion proposal, then the project entity shall reject the certificate unless any such difference is minor or all members vote otherwise.

Could this keep another open season from happening?

The question and the predicate don't work. But the answer is no to the question that was asked.

Open season requirements exist --

well, let me change that. What Congress designed was open season requirements, and if I remember this correctly, except for a mandatory expansion. It said -- and the FERC order, I believe, captures this, I'll double-check it -- that the open-season requirements apply to anything the pipe does unless it is ordered by the FERC to expand. So the open season requirements apply to a voluntary expansion, but not to a mandatory expansion.

And the reason for that, if I remember the statute correctly, is the statute said, this is a special right we're creating, this new power, mandatory expansion, and we want the person who filed the petition at the FERC for the mandatory expansion to commit to the expansion. You're the guy who made the trouble. You have to accept the capacity, as I recall, within a period of time. It may be 90 days or it may be a year after the final expansion order comes out. So, Congress drew a distinction on the open season requirements.

So, I'll think about this some more, but I don't see where -- and then we created this third expansion right. But since the expansion certificate comes after an open season and our special expansion provision provides for an open season, I don't see how this new section would frustrate an open season. But there -- there may be something more that I'm missing there.

FERC also proposed rolled-in pricing for any expansion. There's no commitment in the contract to use rolled-in pricing. Could the producers ignore this in their application to FERC for expansion?

No, I don't think you ignore the law. I think you do that at your peril. The law is on the books. They have to overcome what FERC said about rolled-in pricing in the open season orders. They could try for an exception to a policy, but they can't ignore the policy. It's on the books.

And one of the interesting things, I think, in choosing what issues they chose to file a court appeal on, they did not challenge the presumption FERC established for rolled-in pricing. That's not an issue on the appeal, so they left that alone.

I think they left it alone. I

suspect they left it alone on the basis that's an issue for another day. We don't know what we're talking about on an expansion until one is presented to the FERC in 10 or 20 or whatever years.

Nothing in the contracts shows any inclination to be friendly towards expansion. Silent on voluntary expansion. Guidelines are hard. No incremental schedule. Please comment.

I sort of have said this three times. There are three ways that expansion can occur, and we did not -- and I think it would have been a mistake -- incorporate in the contract everything that the current regulations provide. You have to have some respect for the body of existing law as it stands.

I thought that by adding to statutory mandated expansion and the possibility of voluntary expansion, which is addressed in the LLC document, how that occurs, and then adding to it a third category of expansion rights, we were friendly towards expansion.

How can the interest of the Port Authority be protected under FERC and open access? If Port Authority has a viable project, how can they bid in gas under FERC?

Again, we've touched some of this. The Port Authority, like anyone else who wants to ship, can bid for that intrastate shipment rate capacity based on that intrastate shipment rate in the open season. And -- and if they succeed in their bid, then they have the right to ship gas in state to the point they take it off to a lateral that would be regulated by the RCA. But they're not precluded in any sense from bidding in the process. And I'll have to check but I know in urging the need for a separate intrastate rate in the open season process -- and remember, we got that, there was talk about that open season intrastate rate would be evaluated separately than the bids for the long-haul rate. But I will check that.

It says: The producers have rights to get their new gas into a pipeline as compared to new finds by the pipeline owners. Oh, here's the rest, sorry. That was the second half of the page.

Commissioner Menge gave an example, maybe incorrect, of the company that finds gas and must wait 20 years under open season rules to access the pipeline. Will independent producers have rights to get their new gas into pipeline as compared to new finds by the pipeline owners?

This has some complexity to it. As I've said, anyone can bid in the open season. You, depending on the rules that are established, may not even need to have gas. You're buying transportation rights. That's what the open season sells you, transportation rights on the pipeline.

A second fact is that right now there's not enough gas to fill the pipeline for its designed capacity. So, we have this sort of schizophrenic approach to this. On the one hand, everyone says there's not enough gas known to fill the pipeline, and on the other hand, people are saying they're going to be precluded from getting on the pipeline.

My point -- one of my points is that if I am holding excess capacity, meaning I signed up for 20 years, I have gas for 15, and a third company comes along that -- or a fourth or a fifth, that has found gas and I haven't found gas, I'll be delighted to release that capacity. In some cases I have to release that capacity to the person who has gas, because I don't want to pay a reservation charge for my capacity when I have no gas going through it. That's -- that doesn't make economic sense.

If, in fact, all the capacity is used, meaning people signed up for it, they have gas to fill it for its whole term, that whole term is 20 years, that's the case where the independent shipper -- potential independent shipper can -- what -- what he would do, if he or she were smart, is they would go to the pipeline and say, I'm going to go to FERC and, you know, file a mandatory expansion petition unless you tell me you're going to build some capacity. I've got the gas to ship. You're holding the capacity back. What are you doing?

And I know in the legislative debate and since, the major North Slope producers have said that that expansion -- mandatory expansion right will never be used because it's a club that exists at the end, and as long as it exists, the pipeline will negotiate. Time will tell on that.

But in the -- again, in the hypothetical, where there truly is not an ounce of unused capacity on the project, then it would -- A, it would be in the project's economic interest to expand; and, B, you could invoke the mandatory expansion rights at the FERC and go through that process.

I want to make another point about expansion open seasons which, I think, has been missed in some of the debates.  If there's an expansion open season, nobody is entitled to that expansion capacity; not the pipeline, not the affiliate, not the independent.

The person who should win is the person who makes the most successful bid, the highest-value bid in the expansion open season. So, we -- we talked informally:  Is there a way that you could make sure that the expansion capacity is reserved for independents?

If you do that, you run smack into the problem that the open season is supposed to be nondiscriminatory.  So, it's supposed to evaluate all bids that come in on an equal basis.

So, unless you create a preferential right, which would seem to violate the principle of nondiscrimination in an expansion open season, it would seem that the new shippers would have to take their chances against the affiliates, but they have the opportunity to be judged fairly and nondiscriminatorily on their bids.

Page 238 of the fiscal interest finding indicates that any single member of the pipeline LLC can veto the project at the moment of project sanction. Please explain the benefits of such a veto power.

Well, in multi-company projects we're depending on the credit of three or more companies, the benefit is -- I don't know if it's a benefit, it's just a neutral statement -- you want everyone behind the project. That's the benefit. And you cannot -- as I've said before, this is the time when the huge financial commitments are made. And you can't force people to invest their capital. If company X or company Y at that point decides the project isn't viable, then a number of things could happen, one of which, theoretically, is the project could go ahead with the other companies and you could bring in a new partner. But you -- the benefit is just it protects each investor's right to make a sound economic decision on whether the project is viable at the time when they have all the facts and permits before it.

There's one question on 8.6 on previously used assets. I'm going to just defer that and take it up, I promise, with 8.6 and 8.7.

Will rolled-in tariffs be applicable for expansions? Again, we should check the text, but as I recall, there's a set of expansions that it's not applicable to, and to every other one, it's presumed to be applicable.

Any more questions?

COMMISSIONER CORBUS: We're out of questions, and it's a good time for a break. Let's take ten minutes, please.

[Break]

COMMISSIONER CORBUS: Our speaker for the remainder of the day will be Bob Loeffler. Before he comes up to the podium, I just -- a couple things I wanted to -- announcements to make.

No. 1, yesterday there was a question or a request for the list of all the individuals and organizations that signed the confidentiality agreement, and there is such a handout located on the table out in front of the room for those that are interested.

No. 2, we've had a slight confusion, and the PowerPoint that -- the second PowerPoint that you have before you, which Mr. Loeffler is going to follow, is slightly different from that which is going to appear on the screen, and a revised PowerPoint will be delivered to you sometime during the presentation to -- this afternoon.

Mr. Loeffler is going to briefly close off on the EIS process and project sanction and is going to spend most of his time on discussing the contract provisions.

Mr. Loeffler.

MR. LOEFFLER: I want to go back on one point that I checked over the break.

The open season regulations, by their text, apply to any initial open season and any voluntary expansion. They do not apply to a mandatory expansion. That's the line the FERC drew. And I believe the reason was -- is what I stated, that the mandatory is like one party initiates and they want to hold one party to that commitment. But that is how the regulations divide themselves today.

I -- I see the topic was not only the FERC process, but the EIS process, and project sanction. I -- I have touched upon those, I think, in sufficient detail. But let me spend a minute or two more in case I didn't.

The NEPA process is any major federal action affecting the environment, calls for the preparation with environmental assessment. And that statute was adopted, I believe, during President Nixon's presidency. And there's a lot of law developed. But it's a way of making sure that before federal regulators take any action, that they know and understand the environmental consequences of the action.

The law that has developed is that NEPA is generally not regarded as a substantive requirement but is a procedural requirement. So there is a D.C. circuit case, indeed, in the Beaufort Sea lease sale involving the State of Alaska where the court, then said -- this was about '79 or '80 -- that the environmental -- as long as you know what the environmental consequences are and have assessed them, you do not have to choose the best environmental outcome.

So it's really a way of informing the regulators, but not dictating the result.

The -- the way it's done is the proposed project is put out -- usually the federal agencies have some staff, but they'll hire a contractor to do it. And it really is a very long document that looks at the environmental consequences. And the ones I've seen include socioeconomic consequences. And, indeed, we used it early in the '80s to force an assessment of alternatives or the size of a conditioning plant and some petrochemical options for the ANGTS, originally.

But it looks at economic consequences, environmental consequences, socioeconomic consequences, and then comes up with a list of mitigation measures. And you need a fair degree of project definition, because you can't suggest that on mitigation that you should avoid a particular area or not cross a river or a stream or go a different way through a mountain or go underground or overground unless you know, basically, where the project is going. So that's what's involved in the environmental assessment process.

Typically, there's a public process connected with that also, and then there's this draft environmental impact statement, and my office is filled with them, but they are hundreds and hundreds of pages for a project like this. And then there'll be a public comment period. And then they typically -- not always, but typically respond to the comments in the final impact statement. So, you'll sometimes have it at the end of the draft -- rather, at the end of the final impact statement, a list of every significant comment. Sometimes they're grouped in their response to those comments.

So it's a way of involving the public, an environmental assessment, making sure that an environmental assessment occurs. There's no way of skipping it on a project this size. The environmental reports that were done for the ANGTS are 20 years or more out of date. There's some value in them, but I -- I wouldn't overestimate the value.

And it's important that Congress establish a deadline of 12 months and 18 months to get the job done so as not to slow the final permitting of the project.

I referred also to project sanction, and I -- I was correct. The -- it's page 238 of the fiscal interest finding, and I -- I'd spend a moment more, but it is the standard corporate way of deciding how to make a big decision.

Now, you may think that it's a big decision to spend $200 million on front-end engineering and design or another $100 million on the studies and consultants and whatever that go to file a FERC application. And those are steps along the way, and you'll hear more about those, I think, from IPA. The big decision, the sort of decision to go to war or make the investment is the project sanction decision. It has different names in different companies. But it's a board of directors' level decision.

And, really, it's almost a two-step process when you think about it for this project. You take Exxon or BP or ConocoPhillips, now each have made a decision internally, evaluating all the permits and the financing and the engineering and the risk profile and the market studies, that they want to direct their individual member of the -- say, the pipeline LLC to vote to go ahead with the project. So, in a way, there will be two sets of project sanction decisions, one made internal to each company and then a final one made when they -- in the context of the LLC, when they go ahead and they vote to go ahead.

I really think the description on 238, and I didn't write it, is a very good description of the project sanction process, as far as we can see it today.

So, I close off the first presentation with those additional comments.

Now, on the fiscal contract presentation, as you know, that's scheduled to go today and tomorrow and, in some respects, days after that, and some topics have been covered already. I -- I had a slide prepared, but I don't think it made it up here. Oh, it did. Miracle.

That's the -- just the table of contents of the fiscal contract. And when you look at it, in one sense, every part of the contract has some fiscal consequence. But when we're talking about the fiscal terms of the contract, we really start with the overall fiscal stability covenant, Article 11, and then it goes logically: Royalty payments, tax payments, payments with gas instead of tax, cash. A term you're going to hear a lot about: PILTS, payments in lieu of production taxes or payments in lieu of taxes, a PILT. Then various payments. So you look at the sequence from 11 through 22. 22 is called the waterfall, which is how the State gets paid and how the State pays and what happens if the State doesn't pay.

11 through 22 are the core of the fiscal terms of the contract. And Dan Dickinson is preparing materials and will cover those starting tomorrow.

I am going to talk about, principally, the nonfiscal terms. And what I've done, if this works, is I've grouped a number of articles together. Because, for example, the first subject I'm going to talk about is term, termination and withdrawal, and there's a sort of connection between how long it is and how you get out of it. And, hopefully, we'll cover everything.

Now, I know that work commitments and Alaska hire and, I'm told, Point Thomson and capacity have been covered already, so I don't propose to cover those under the theory that once is enough. But if there are questions, we can take those up.

The other point is there are some illustrative parts, attachments to the contract, and they have a certain hierarchy within the contract, but I'll get to that when I get to it.

So, here we go.

The qualified project description, which is Article 4, is a term of the contract that really fits into the Stranded Gas Act. Section 43.82.100 requires there to be a qualified project plan and, within that, a qualified project. And so what Article 4 does, and it doesn't do much, is it lists the main components of the project.

You'll notice at the bottom that it says: A potential pipeline from Alberta to Chicago. No one knows exactly what's going to happen there. A lot of gas will be coming into the Alberta hub. As you heard Pedro say the first day, I believe, we've modeled the economics on gas going to Chicago or gas going to Alberta or a combination of the two.

There is various ways that gas

could be taken out of Alberta, if not sold at the hub, to various places in the Lower 48. And I believe the project has made a decision that wherever possible they're going to use existing pipe rather than build new pipe. Because there's a lot of spare capacity south of Alberta, and it makes sense to use the spare capacity, provided you could get decent economic terms.

The second slide says, essentially, what I just said, but adds the important point that the qualified project plan will be amended and brought up to date once a year as the project develops. And I made reference to the new project summary that was filled -- excuse me, was filed with the State on May 10th and that we're going to make available.

Now, let's get to a major element. The State ownership -- this is the misnomer of calling 11 through 22 fiscal, certainly the amount of pipe the State will own is -- is fiscal in some sense, but we had to divide it some way.

There will probably be a series of LLCs as the legal vehicle to own each little piece of pipe. And there will be the mainline LLC. The gas treatment plant may be in that LLC or may be a separate one. There will be one for each of the upstream feeders. In Canada, the legal structure might be different just because of Canadian law. And, so, when you look at the definitions in the contract and you look at the ownership provisions, you'll see they're broken up by pieces.

The second point is important: Each LLC will have an LLC agreement, which is -- we're negotiating the master agreement, really, for the mainline LLC, as we speak. It's almost done, but there are still some issues there that we're trying to iron out in the next week or so. One of my partners is working hard on that. But they each have a governance document which sort of implements the general concepts that are in the fiscal agreement, and they have voting provisions, and they have withdrawal provisions, and they have financial contribution provisions. But as I've said, the mainline one is intended to be the model for the others, so everyone is spending a lot of time on it.

Here are the 20 percent pieces. And what does 20 percent mean? Generally, the idea is to match up the amount of gas you have with the amount of pipe you have, even though legally owning 20 percent of the pipe doesn't give you the right to 20 percent of the shipping rights.  So it's an economic matchup, not -- not a legal matchup.  And the contract, Article 7, provides:  The State shall own 20 percent of the treatment plant; the pipeline in Alaska, which is called the mainline; the pipeline from Alaska to Alberta, meaning to the Alberta hub; and a liquids plant if located in Alaska.

In terms of these other pipelines, and these are existing units, the State is going to own a percentage of those that matches the amount of State gas that will flow through those. And because royalties aren't the same on all of those, the percentage of State gas won't be the same on all of those.  And the time that you will measure what your percentage is, you'll say:  How do I know?  You know, they're very -- we could do an estimate today.  That doesn't mean anything. We don't know what -- how much gas is coming out.

When the legal entity is formed for each of those transmission lines, like a Point Thomson line or a Kuparuk or whatever, when the legal entity is formed, the State percentage will be determined.

There may be or we hope there will be a pipeline to transport gas from west of the Kuparuk River boundary, and really we're thinking of NPR-A -- and it will be -- we have the right to acquire -- the requirement of requiring -- of acquiring an interest in the transmission pipeline if it's sanctioned prior to the commencement of commercial operations.

After that point, we have an option to acquire. In the one case, we're in the system. In the other case, we have an option to take a piece.

We wanted to have some sort of temporal limit rather than have an unconditional obligation, so we picked that time.

The same idea applies to a new pipe or acquired pipe from Alberta to the Lower 48. Remember, we don't know if there's going to be such a pipe. Again, we don't know how much State gas would be going in that pipe. Since there's one theoretical possibility that the State sold all its gas in Alberta, why should it be obligated to take a piece of pipe south of Alberta if it's not shipping any gas south of

Alberta?

I can't say whether that's likely or not, but this gives us the right to have a piece of that pipe, you know, measured up against the expected throughput of State gas on that pipe at the time that legal entity is formed.

The State is also obligated to maintain its ownership for the pieces of pipe that are listed there in the treatment plant until the State has executed a binding precedent agreement to reserve capacity. And the implication of that -- but this will depend on the final LLC language -- is that the pipe -- the State can get out of its pipe after that time.

In the case of the Alberta to Lower 48 pipe, the language reads a little differently. Because we don't know whether we want to be in that pipe. We don't know whether we're going to be shipping in that pipe. So, if we don't execute a shipping agreement for that pipe, we're out of it. So that could expose us to some planning costs, our share of planning costs, but not the actual cost of constructing the pipe. Because, remember, the open season, when you make the binding agreement, is before the construction.

The general idea, to conclude that section, is that we wanted to measure up our throughput and our share of the pipe, which is the best place to be economically.

You might say:  How did you get to 20 percent?  Well, two things were negotiated, and this may have been covered already.

There was, of course, what percentage the tax gas would be, that's 7.25 percent, and what percentage the royalty would be.  And I think Dan will say, and it's true, that there were efforts made but rejected to modify the royalty percentage.  The royalty percentages are what they are under the leases or are what they will be under the leases.  But if you add it up today, it comes out to 19 -- 7.25 for tax gas, and then you add the various royalties, and it's 12-something.  So you come pretty close to 20 percent.

So, the negotiation of royalty and tax percentages of gas and percentages of the pipe aim for the same objective.

The contract is effective on a date when it's executed by all the parties and that's after the Legislature gives its blessing. And the term commences on the effective date, but for the gas provision ends 35 years following the commencement of commercial operation of the pipeline.

And, again, the fiscal interest finding addresses the reasons for that term, and I believe other people have. If not, I can get into it a little bit.

There are exceptions for the -- essentially the oil provisions. There are three exceptions and they're given here. And it is not a typo that one of these ends December 2036 and one ends December, 2035. For some reason, maybe because of the difference in time when those were negotiated or something, those are literally what the contract provides.

And the SCIT one is exactly as stated there.

But there was a lot of a -- a long, long discussion extending over months, if not years, on whether fiscal certainty would be extended to oil, and if extended to oil, what the right term of coverage was. And the oil provisions kick off on the effective date and, last, a defined term.

The gas provisions kick off on the effective date, but the term is measured from the commencement of commercial operations, which is the language in the statute. So that 35 years goes from the commencement of commercial operations, which is some time out, plus however long it takes to get to the commencement of commercial operations. But in no event is the term exceeding 45 years.

There can be force majeure events; acts of God, acts of law, strikes, epidemics, all sorts of Biblical things. And they can extend the term, but not beyond 45 years.

How can the contract be terminated? There are various ways. Again, work commitments have been described, I believe, by Pedro. And if the State believes that the participants, which means the companies, have failed to advance the project diligently, the project sanction, the State can bring a termination claim within the arbitration process, and the contract can be terminated if the State wins its claim, and I'll get into some of that.

There are still some grounds for an

administrative termination, which is triggered by the -- an action of the Commissioner of Revenue, and then all of the parties could agree.

There are other circumstances of withdrawal as opposed to termination, and I'll get into those.

The standard that the State would have to meet to terminate the contract is it has to show by clear and convincing evidence that a participant failed to diligently advance the project as may be prudent under the circumstances resulting in a material adverse impact on the project.

Sounds like a lot of lawyer work. It took months to get a work commitment clause. We tried all sorts of different language and standards. This was a hotly negotiated clause. And, of course, the starting position of the companies, or at least some of the companies, is that they did not want to commit to a work commitment of any kind because they said there were too many variables and unknowns.

The State persisted in its effort to get a work commitment clause, and we worked hard on the concept of diligence, and we also wanted consequences on the project. There was a thought at one point that we rejected, that the consequences should be on the State as opposed to on the project. But, really, what we're concerned about is the project getting delayed. And so we came up with this language.

This is submitted to arbitration and tomorrow you're going to hear about the arbitration or dispute resolution process.

There was a lot of back and forth about what the tribunal has to look into or should look into in making its decision. Remember, we're dealing with an arbitration tribunal composed of three neutral arbitrators. So a lot of language about burden of proof, clear and convincing evidence has limited value in -- in my mind because you're not talking about a jury trial. You're not talking about a judge instructing the jury they've got to prove something beyond a reasonable doubt. I -- but there is -- it does have some value, but arbitrators, in my experience, sort of look at the overall result. And, yes, we negotiated terms it's had to look at. What are the causes of delay? The point about errors in judgment was that it is common to make mistakes in building a very large project. Those alone are not a cause for termination. The fact that there is a presumption that the contract continues is, in fact, what we believe arbitrators would do anyway. They don't likely upset contracts.

When you invoke or when the State invokes the Article 26 procedures under the work commitments clause, there is no informal step of trying to work things out. Under the -- any other dispute with, again, a few exceptions, there's an informal step when a party notices a dispute and the party says, let's get senior representatives together to see if we can solve this. We felt that if the State were going to take the serious step of terminating the contract, there was no point in wasting time with the amicable step, amicable resolution, which would have added three or four months to the process.

The only issue is whether clear and convincing evidence is presented, and it will be a yes or no vote. It's not a maybe. It's not an explanation. Yes or no.

And that will be made public.

If the State starts one of these termination procedures, other participants have the right to suspend work without penal -- without any penalty pending the resolution of a termination procedure. And, again, from the company's point of view, the idea was that termination or the start of a termination process means the State is very, very unhappy. It's a very serious step, and they want to be able to pull back and litigate it to conclusion. And litigate to conclusion is within a defined period of time.

They do have the right to cure whatever the deficiency is, and these are the time periods. If they don't send a notice to cure, the contract terminates, I believe, after 60 days.

If they start a tour, they have 60 days to make a serious effort to cure whatever the State problem was that led to the termination notice. I'm going to come -- I'd just note that there is administrative termination, and I'm going to go on to something else, and then it comes at the end of this PowerPoint.

Consensual termination speaks for

itself.

One thing that I think has been overlooked is Article 31, which talks about withdrawal rights of the companies, and that's who a participant is. That's a defined term.

The companies insisted they have in all their contracts the right to withdraw from a project, and we picked the time as prior to the execution of a precedent agreement. If a company withdraws, they lose the fiscal certainty under the contract. So, that's a pretty serious step.

After the open season, it gets even more serious. If a company withdraws after the open season, they have to leave behind their interest in Alaska and their interest being not only pipeline interest, but their interest in any gas leases or units they have that are subject to the protection of the contract. That's that Exhibit D to the contract, which lists all the leases. And they lose fiscal certainty.

Now, they can leave it behind by selling their interest, but if -- if they withdraw after the open season, they're, in essence, withdrawing from Alaska and leaving behind whatever they have. May get some value for it; they may not.

So, that is a pretty serious step.

It seems to me, given the high emphasis that they've placed on fiscal certainty, it's even a serious step to withdraw before open season because you lose the benefits of the fiscal certainty contract.

If one company withdraws, the rest are committed to the contract, and the termination occurs 60 days after delivery of notice.

Now, the administrative termination rights are defined in Article 28, and in the definition in the beginning of the contract. We tried to place all the definitions in the beginning of the contract except for some pocket definitions.

And the administrative termination rights can be invoked only during a defined period. It's the period between the effective date and the point of which the companies have spent a total of $125 million on midstream entities, on pipe, in other words.

Just on a humorous note, one of the mistakes that was corrected is that the

PowerPoint we originally distributed had the Department of Natural Resources Commissioner having the rights to administrative termination, when, by statute, they're the right of the represent- -- of the Department of Revenue Commissioner. Now we've corrected that.

We didn't want to take any of your powers away, Bill.

This starts with an administrative process. The Commissioner sends a notice and saying I'm terminating you. And there are two ways it could happen. If there is an -- essentially fraud, but an intentional misrepresentation of material facts upon which the contract was made. Something fundamentally incorrect was sent to the State. We can terminate the contract.

The idea here is that if such a misrepresentation were made, we should know that pretty soon. And certainly you should know it by the time $125 million has been spent.

The other ground we retained is that the participants as a group no longer meet the requirements of a qualified sponsor group under the contract.

Actually, this slide is generalized. It could happen, I believe, that an individual participant could fail, but, really, it's more likely that the -- if the grounds for administrative termination arose, it would be under the second point.

Again, there's a right to cure after the notice. And if the affected participant says I did not misrepresent or I'm still qualified or whatever and the contract stays in effect, then you go under the Article 26, dispute resolution process.

Again, if the Commissioner seeks to terminate the rights of all participants, the project entities may suspend their obligations by issuing a notice. But if it's only one participant who is being terminated, then the others have an option of suspending. And that's an administrative suspension notice, and that remains in effect for a period of time until this resolution of the dispute or until the project entity withdraws the termination -- its notice of suspension.

The financial payments under Articles 14, 15, 17, and 19 must still be made during this administrative termination process. And then if the State loses, additional time is added on to the contract for the period the suspension notice was in effect, added on as to whatever obligation was suspended.

And if the State wins, the contract terminates in relation to that participant.

That is what I had hoped to cover today. I'm sort of, as you can hear, running out of voice, and I will recover overnight, I hope.

But we have time for a few questions within our schedule.

I guess we have questions.

COMMISSIONER CORBUS: Nine questions.

MR. LOEFFLER: Nine questions.

What is the projected cost of the interest that the State must acquire in transmission pipelines at Prudhoe, Point Thomson, Kuparuk, Duck Island, Badami. At what stage of the contract does this transaction take place?

Let me take the second part. First, as I said, it's usually measured amount of State -- the percentage is equal to the percentage of State gas in that pipeline. At the time the project entity is formed, the project entity will have a schedule of commitments for financing, and it would follow whatever the schedule is in that contract.

What is the projected cost of the interest the State must acquire at Prudhoe, Point Thomson, Kuparuk, Duck Island. I'll have to check that. I know there have been estimates on Point Thomson that range up to 2 -- not of the State share, but of the whole project, you have 200 to 400 million, but they're very loose. So it would be 20 percent of that, so a maximum of 80 million. Prudhoe, it's a tiny amount of pipe. And the others, it's very small. I don't know that we have a current number, but I will see if we do.

Why have you imposed such a high burden of proof by clear and convincing -- it's proof, I think is the word, on the State? Discuss both 1 and 2 --

Let me see this again.

Why have you imposed such a high burden of proof, one, by clear and convincing evidence, two, on the State?

Well, the second one is easy. It's

the State who wanted the right to terminate the contract under the work commitments clause. It wasn't the companies. So, logically, the party who is moving for the action would have the burden of proof.

And, clear and convincing evidence, it's not beyond a reasonable doubt, it's not by a preponderance of evidence, it's in the middle. And we felt in the end the -- as -- as I discussed, that it didn't make much of a difference in arbitration.

Is State ownership of facilities really optional? If the State were to decide not to participate and the producers had to pick up that investment, it would change the internal rate of return for the producers.

The second is: That's a true statement, if they have to invest more, it will change their internal rate of return. And I guess what the question really means to ask is: If the additional investment would lower the internal rate of return beyond their threshold, then the State doesn't have the option of investing because the threshold wouldn't be met anymore.

And I think Pedro addressed that, and I bow to his judgment. I would say investment in the main project is necessary to meet the economic targets that the producers have for an investment of this magnitude. So, in an economic sense, if the State wants the project, that analysis would suggest that it's not optional. I think when you get to the little pieces of the project, it's more of an open question.

If the Legislature approves the contract, how long is the State on the hook or bound by the terms if the producers drag their feet?

They're on the hook until they attempt to -- the State attempts and succeeds in terminating the contract under the work commitments clause or the administrative termination clause.

It seems that if a producer truly believes it is prudent for its company to put more resources into nonAlaska projects, thereby slowing down its work on the project, it can argue it has met its duty to be as diligent, as prudent. Explain to us how we could prove by clear and convincing evidence this is not okay under the contract language.

We actually had some internal discussion of this. We -- we would argue that the standard is for this project, and that the relevant reference points are of this project, and that is what we would seek to prove and hopefully succeed in proving.

I -- I've thought that, as I've said before, and this is my personal view, that there will be an increasing momentum on the project. The project has obvious huge economic benefits to the producers. Pedro has outlined those. I've seen his presentation. And I think the prize is so great that the more they spend, the faster it will go, but that's just my personal view.

Do we receive the 20 percent GTP ownership through the 35 percent GTP tax credit, or do we have to invest an additional 20 percent equally, and in effect a 55 percent investment?

I think the -- let me duck on this one for the following reason: The GTP tax credit is in discussion, I believe, in the PPT discussions that are going on. And until I know where that comes out, I will avoid answering that question. But I will be happy to answer it once I know where it comes out.

Slide 15 states: The provision for payment in lieu of oil pipeline ad valorem tax. What is ad valorem tax? Dan's the best person to answer, but ad valorem tax is -- is like a property tax imposed on oil pipelines, is the easiest way to answer. And there's a fight every year about what the proper value of TAPS is, for example. And part of that guts to municipalities, and that's always resolved. But that's what an ad valorem tax is.

The normal standard of proof in contract cases is more likely than not. I don't know where that -- I don't know what the foundation of that statement is. But I'll accept it for the time being.

Please explain the difference in the higher clear and convincing evidence that the State must meet under this contract. It is harder to prove, isn't it?

Well, I've touched on this. We -- we experimented in negotiation with various standards. It is not the highest standard, and it is not the lower standard, at least linguistically, of more likely than not. We thought in the end that it would not make much difference in the way an arbitration panel, as opposed to a court, would decide the case.

That's it.

COMMISSIONER CORBUS: That completes the presentation for today. We will reconvene tomorrow morning at 9:00 a.m., and we will continue to go through the contract provisions with Bob Loeffler and Dan Dickinson.

Good evening.

[Legislative Special Session adjourned at 4:26 p.m.]